BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF INTER-JURISDICTIONAL ISSUES AFFECTING PACIFICORP DBA UTAH POWER & LIGHT CO.	)))))	CASE NO. PAC-E-02-3 DIRECT TESTIMONY OF DAVID L. TAYLOR

SEPTEMBER 2003

Q. Please State your name, business address and position with PacifiCorp ("the Company.")

A. My name is David L. Taylor. My business address is 825 NE Multnomah Street, Suite 800, Portland, Oregon 97232. I am employed by PacifiCorp as Director, Revenue Requirement and Cost of Service.

Qualifications

Q. Please summarize your education and business experience.

A. I received a Bachelor of Science degree in Accounting from Weber State College in 1979 and a M.B.A. from Brigham Young University in 1986. I have been employed by PacifiCorp since the merger with Utah Power in 1989 ("Merger"). Prior to the Merger I was employed by Utah Power, beginning in 1979. At the Company I have worked in the Accounting, Budgeting, and Pricing and Regulatory areas. From 1987 to the present I have held several supervision and management positions in Pricing and Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified on numerous occasions in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

Purpose

Q. What is the purpose of your direct testimony in these proceedings?

A. My direct testimony is in support of the Company's request that the Commission ratify the PacifiCorp Inter-Jurisdictional Cost Allocation Protocol ("Protocol") contained in Exhibit No. 3. Appendix A to the protocol is a list of defined terms. For purposes of greater clarity and consistency, when I capitalize terms in my direct testimony, and do not otherwise define them, it is intended that those terms have the same meaning as provided for in Appendix A to the Protocol.

My direct testimony covers three areas. First, it provides the basis for the allocation procedures used in the Company's proposed inter-jurisdictional cost allocation method, which was identified as the "MSP Solution" in Ms. Kelly's direct testimony. This portion of my direct testimony discusses the classification and allocation of generation and transmission costs, the treatment of non-tariff Special Contracts and the treatment of the Hydro and Coal Endowments and certain new baseload Resources. Second, my testimony considers the implications of disproportionate load growth in one State on the revenue requirements of other States. Finally, my testimony estimates the impact of the MSP Solution on the overall revenue requirements in each State.

Allocation Procedures

Q. Please summarize the procedures that the Company proposes to follow in allocating the costs of generation Resources.

A. The allocation of a utility's costs employs a three-step process generally referred to as "functionalization", "classification", and "allocation". The use of these three steps recognizes the way a utility provides electrical service and attempts to assign cost responsibility to the groups of customers for whom those costs were incurred.

Functionalization, the process of separating expenses and rate base items between the generation, transmission, and distribution functions, is generally not at issue in MSP.

Classification is the process of separating costs between those which are Demand-Related, Energy-Related, or Customer-Related. Demand-Related costs are the capital and other fixed costs incurred by the Company in order to be prepared to meet the maximum Demand imposed on generating units, transmission lines, and distribution facilities. Energy-Related costs are costs (such as fuel costs) that vary with the amount of Energy actually generated plus any portion of Fixed Costs that have been classified as Energy-Related. Customer-Related costs are those that are primarily driven by the number of customers served.

Allocation is the process of assigning Demand, Energy, and Customer-Related costs among States or customer groups. This is achieved by the use of allocation factors that specify each State's share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor determines each State's share of cost.

With the exceptions that I will describe later, the MSP Solution is an integrated system methodology pursuant to which customer loads are deemed to be served from a common Resource portfolio. The MSP Solution only deals with the allocation of costs among States. The procedures for allocation of costs among customer classes will continue to be determined independently by each State.

Q. How is your testimony concerning the allocation procedures relied upon in the MSP Solution organized?

A. First, I will discuss the Company's analysis and conclusions on general classification and allocation procedures. Then, I will detail the specific classification and allocation procedures for each type of Resource identified in the MSP Solution.

Classification of Generation Costs

Q. Does the Company propose to continue to classify the majority of generation fixed costs and Wholesale Contracts as 75 percent Demand-Related and 25 percent Energy-Related?

A. Yes. With the exception of Simple-cycle Combustion Turbines (SCCTs), PacifiCorp found no compelling reason to change from the currently employed 75 percent Demand / 25 percent Energy classification of generation fixed costs. We also propose to continue the practice of allocating Energy-Related Costs based upon energy usage. Commissions have generally found that these methods have a reasonable basis in cost causation and changing them would have unwarranted impacts on State revenue requirements.

A discussion paper on the topic of Classification and Allocation of Generation Fixed Costs is presented as Exhibit No. 12. The paper reviews some of the classification and allocation history at PacifiCorp and its predecessor companies. It also draws from the 1992 NARUC *Electric Utility Cost Allocation Manual*, which catalogues a number of classification methods commonly employed by utilities.

It is not uncommon to classify all Fixed Costs as Demand-Related since, in general, system capacity must be sufficient to meet maximum demand and thus costs are said not to vary with respect to energy output. On the other hand, engineering analyses employing system reliability criteria in system planning might reveal that the Fixed Costs of generation plant production are both Demand and Energy-Related, as would analyses showing that peak demand should be met with peaking plant while additional energy loads should be met with intermediate and baseload plant. This is said to justify the inclusion of some portion of energy in the allocation factor to be applied to production plant costs.

Exhibit No. 12 applied the methods discussed in the NARUC *Manual* to PacifiCorp's State peak and energy load data and produced a range of results. Demand-Related production costs could vary from 100 percent, to a low end of 27 percent using the "Average and Excess Demand" method. The Company also surveyed a number of electric utilities serving in other states, finding wide classification differences among them.

The choice of the 75 percent Demand/25 percent Energy classification for generation and transmission plant was the final allocation decision made by the PacifiCorp Inter-Jurisdictional Taskforce on Allocations ("PITA") after the Merger. The PITA analysis also indicated that a wide range of demand and energy classification methods could be supported on a technical basis. The demand/energy classification was the means ultimately used to balance the sharing of merger benefits among all the States. The 75 percent Demand/25 percent Energy classification method was selected because it produced an overall cost allocation result that was acceptable to all the States.

Because no clearly superior demand/energy classification split has emerged from analyses conducted during the Multi-State Process ("MSP"), and because the 75 percent Demand/25 percent Energy classification of generation Fixed Costs currently used by PacifiCorp falls in the middle of the range of reasonable approaches, we propose to continue to use it for all System and Regional Resources and most Seasonal Resources. System and Regional Resources are primarily baseload plants and purchases. The Cholla Unit IV plant, which is identified as a Seasonal Resource, is also a baseload plant and will be classified consistent with the System and Regional Resources.

However, PacifiCorp does propose to change the classification for Simple-cycle Combustion Turbines to 100 percent Demand-Related.

Q. Why does PacifiCorp propose to classify the cost of SCCTs differently from the remainder of the Company's Resources?

A. SCCTs are typically peaking Resources that are used differently from base load Resources, so it is reasonable to employ a classification method that better matches how customers benefit from their use. One of the justifications for classifying the fixed costs of baseload plants as both Demand and Energy-Related is to recognize their design capability to meet both peak demand and to generate lower cost energy all hours of the day and during all seasons of the year. Because SCCTs are designed and operated to run during peak-load periods, rather than produce sustained, low cost energy, we propose to classify their Fixed Costs as 100 percent Demand-Related.

Allocation of Generation Plant

Q. How does the Company propose to allocate the Demand-Related component of generation costs?

A. As with the issue of the demand/energy classification, the Company found no compelling evidence to support a change from the current 12 Coincident Peak ("12 CP") allocation factor for the demand component of System and Regional Resources. We did, however, determine that certain Resources, identified as "Seasonal Resources," were acquired and dispatched to meet customer needs during either the winter or summer periods. To match the cost of these Resources with their use, costs are apportioned across the months of the year consistent with their dispatch. I will discuss this in greater detail later in my testimony as I review each Resource type.

Q. How did the Company decide to use a 12 CP method to allocate the demand component of System and Regional Resources?

A. Since the time of the Merger, PacifiCorp's Demand-Related Costs of generation Resources have been allocated using the12 CP Factor, pursuant to which all months of the year are deemed to play an equal role in Demand-Related cost causation. To determine if a smaller subset of monthly peaks might form a better basis for Demand-Related Cost allocation, PacifiCorp revisited the stress factor analysis that was employed at the time of the Merger.

Q. What is stress factor analysis?

A. Stress factor analysis is a tool used to identify particular months for inclusion in the capacity allocation factor by examining, month by month, the key elements that stress the ability of the system to meet its peak load requirements and therefore drive the need for investment in new capacity. PacifiCorp examined monthly historical and forecast data for three specific stress factors: a) monthly retail peak demand, b) probability of loads in any hour to contribute to the system peak, and c) the cost to bring the reserve margin to 15 percent.

Q. Please briefly explain the basis for each of these stress factors and how it is calculated.

A. Monthly retail peak, also referred to as the monthly Coincident Peak, is one of the most common stress factors. It is the simplest to calculate and perhaps the easiest to understand. It is single highest combined demand measurement of all PacifiCorp retail customers during each month. The Company needs enough available generating capacity to meet this level of load. Months with higher peak loads are viewed to place more stress on the system than months with lower peak loads.

The probability of contribution to the system peak indicates the number of hours in each month with loads that exceed a threshold demand level. The criterion for our analysis was the average available energy from PacifiCorp's owned and long-term purchased resources divided by the maximum peak capacity of those same resources, or approximately 83%. If the load in any hour of the year exceeds 83% of the annual system peak it is considered to contribute to the system peak. Months where more hours contribute to the system peak are considered to place more stress on the system than months where fewer hours contribute to the peak.

The cost to bring the reserve margin to 15 percent identifies months where the Company's owned plus long-term purchased resources are insufficient to meet the reserve adjusted peak load and captures the magnitude of that shortfall. Months where the cost to achieve the reserve margin is greater are considered to be more stressful on the system than months where the cost is less, or even zero. The cost is calculated by subtracting the available generating capacity from the reserve adjusted monthly peak load, or peak load plus 15 percent. When this value is positive, it is multiplied by the monthly cost of capacity. For our purposes, the monthly capacity cost of a simple cycle combustion turbine was used.

Q. What did the stress factor analysis indicate?

A To enable a common comparison between the three stress factors and to make comparisons between months of a given year and between different years several techniques were used. A method, termed "rationalizing", where the peak demand, or other measured value, of a given month is stated as a percentage of the maximum measurement for the year, seemed to be the favored approach.

Exhibit No. 13 summarizes the results of the stress factor analysis for the forecast years 2004 through 2008. The monthly-rationalized percents for each stress factor are shown in columns (A) through (C). Column (D) shows the simple average of the three factors and column (E) shows a weighted average with the monthly peak value given double weight.

As shown in column (A), the monthly retail peak is generally the greatest in July or August. The peaks for all months of the year, however, are within 80 percent of the annual peak with eight months of the year, June through September and November through February, within 90 percent of the annual peak. Only the April peak is less than 85 percent of the annual peak.

The probability of contribution to system peak summarized in column (B). While the probability of summer hours contributing to the peak is the greatest, the analysis also shows strong probabilities during the winter months. It also suggests that, with the exception of April, there are hours in all months of the year that contribute to the system peak.

The analysis summarized in column (C) indicates that the cost to bring reserve margin to 15 percent is again greater in the summer with the winter costs only about half of that in the summer.

The stress factor analyses suggest that winter and summer loads may be more significant Demand-Related cost drivers than spring and fall loads. We have addressed this by segregating Seasonal Resources from other Resources. As mentioned earlier, and as will be discussed in greater detail later in my testimony, the costs of Seasonal Resources will be assigned to the months those Resources are dispatched to meet retail load. The seasonal weighting will assign a larger portion of the Demand-Related costs to the summer and winter months. With this adjustment for Seasonal Resources, the continued use of the 12 CP Factor for the remaining Resources appears even more reasonable.

Q. How does the 12 CP Factor work?

A. The 12 CP Factor determines the proportional share of annual Demand-Related costs that are allocated to each State. For each month of the year, the Coincident

Peak, or the hour during which the combined demand of all PacifiCorp retail customers is the greatest, is identified. For that hour, each State's contribution to the Coincident Peak, the combined demand of all retail customers in that State, is measured in megawatts. Each State's contributions to the twelve monthly system peaks are summed to establish the State's 12 CP measurement. The 12 CP Factor is calculated by dividing each State's 12 CP by the sum of the twelve monthly total system Coincident Peaks, or in the case of Regional Resources by the aggregate sum of the twelve monthly Coincident Peaks of the participating States.

Q. How is the process different for Seasonal Resources?

A. For Seasonal Resources, the process is very similar. The only difference is that prior to summing the twelve monthly Coincident Peaks, each monthly CP measurement is weighted by the monthly portion of the total annual energy generated by the Seasonal Resource. For example, if 30 percent of the annual generation of a particular Seasonal Resource occurs in July, the monthly Coincident Peak for July would be weighted by 30 percent in the calculation of the allocation factor. This, in essence, allocates 30 percent of the Demand-Related Cost for that Resource among States based upon their contribution to the July Coincident Peak.

Q. Why does PacifiCorp propose to allocate the cost of Seasonal Resources differently from the remainder of its Resources?

A. Seasonal Resources are designed to be used more intensively at certain times of year. The proposed allocation method captures this aspect of cost causation. The weighted CP method allocates the costs of Seasonal Resources more heavily to

States that contribute most to system peaks in months in which the Resource operates.

Q. How is the hour of system peak for each month determined?

A. In the case of an historical test period, the hour of system peak is based on metered load data. For each hour of the month, all inputs into the system such as Company owned generation, purchases or interchanges are measured. From that measurement, all deliveries outside the system or to non-retail customers are deducted to arrive at total retail load. The Coincident Peak is the hour of each month during which the combined demand of all retail customers is the greatest.

Each State's contribution to hourly loads is determined in essentially the same way. Each State's hourly load consists of the Company owned generation within that State, purchases or interchanges delivered into the State, plus metered flows of energy into the State from other parts of the PacifiCorp system. From that measurement, metered energy flows out of the State and deliveries to non-retail customers are deducted to arrive at that State's retail load.

In the case of a forecast test period, the system Coincident Peak and each State's contribution to that peak are forecasted along with retail Energy usage.

Allocation of Energy Costs

Q. How does the Company propose to allocate fuel and other Energy-Related costs?

A. For System and Regional Resources, fuel and other Energy-Related Costs are allocated using each participating State's share of annual system energy usage. For each type of Seasonal Resource, other than Seasonal Contracts, Energy-

Related Costs are allocated using weighted monthly energy usage. Similar to the weighting of Demand-Related costs, each State's monthly energy usage is weighted by that month's portion of annual energy generation for the particular Resource. The annual fuel costs for that Resource are then allocated using its seasonally weighted energy factor.

Cost Allocation for Regional Resources

Q. Are the costs of Regional Resources allocated differently than the costs of System Resources?

A. Yes. Regional Resources consist of: a) the Hydro Endowment, b) the Coal Endowment, and c) the First Major New Coal Resource. Costs of Regional Resources are, in the first instance, assigned to fewer than all States, depending upon the nature of the Regional Resource. Once this assignment is made, costs are allocated among the assigned States using the same methods that apply to System Resources.

Hydro-Electric Resources

Q. Please explain how the costs of Hydro-Electric Resources are assigned and allocated.

A. The MSP Solution assigns the existing and future investment and operating costs of Hydro-Electric Resources, including those associated with relicensing, to the former Pacific Power States. Participating States are then allocated their proportional share of the Hydro-Electric Resource costs using the Divisional 75 percent 12 CP / 25 percent annual Energy allocation method, or DGP (Divisional Generation - Pacific) factor. The DGP factor is calculated using the classification and allocation procedures described above for System and Regional Resources. However, because this is a Regional Resource, only the loads of the former Pacific Power States are included in calculating the allocation factors.

Huntington Resource

Q. Please explain how the costs of the Huntington Resource are assigned and allocated.

A. The MSP Solution assigns the existing and future investment and operating costs of the Huntington Resource, including those associated with clean air initiatives, to the former Utah Power States. Participating States are then allocated their proportional share of the Huntington Resource Fixed Costs using the Divisional 75 percent 12 CP / 25 percent annual Energy allocation method, or DGU (Divisional Generation - Utah) factor. The DGU factor is calculated using the classification and allocation procedures described above for System and Regional Resources. However, because this is a Regional Resource, only the loads for the former Utah Power States are included in calculating the allocation factors. The former Utah Power States are also allocated their proportional share of the Huntington Resource Energy-Related Costs using the Divisional Energy, or DEU (Divisional Energy - Utah) factor.

First New Major Coal Resource

Q. How does the proposal to permit Oregon to "opt-out" of the First New Major Coal Resource affect the allocation of generation costs?

A. If the Oregon Commission elects this option, costs of the First New Major Coal Resource would be assigned to the remaining States. The costs of the Resource would then be allocated among those remaining States using the classification and allocation procedures described above for System Resources. Fixed costs will be classified as 75 percent Demand--Related and 25 percent Energy--Related with the demand component allocated using the 12 CP Factor. Energy costs will be allocated using the Annual Energy Factor.

Also, should Oregon choose not to participate in the First New Major Coal Resource, an alternate baseload Resource of equivalent vintage and size to Oregon's proportional share of the coal Resource would be assigned to Oregon in its place. Otherwise, Oregon would be avoiding the cost associated with a new, undepreciated Resource and replacing it with a disproportionate share of lower-cost resources from the largely depreciated embedded portfolio (which consists largely of coal-fired Resources). Assigning Oregon the cost of an alternate non-coal-fired matching Resource matches more closely the economic effects of Oregon's policy decision.

Should Oregon choose not to opt out of participation in the First Major New Coal Resource, costs of the Resource would be treated as a System Resource.

Cost Allocation for Seasonal Resources

Q. Are the costs of Seasonal Resources allocated differently than the costs of System Resources?

A. Yes. Somewhat different procedures are used for simple-cycle combustion turbines, Seasonal Contracts and the costs of Cholla Unit IV.

Simple Cycle Combustion Turbines

Q. How does the Company propose to classify and allocate the costs of Simple-Cycle Combustion Turbines?

A. As described earlier in my testimony, the fixed costs of SCCTs are classified as 100 percent Demand-Related. Both the Demand-Related and Energy-Related Costs are then assigned to the individual months of the year on the proportional basis of the annual dispatch hours for the given month in which those resources are dispatched to meet retail load. Mr. Duvall describes how these values are determined.. The aggregate Demand-Related Costs of the turbines are allocated to States using the Simple-Cycle Combustion Turbine dispatch weighted 12 CP (Seasonal System Capacity Combustion Turbine or SSCCT) allocation factor and the Energy-Related Costs are allocated using the Simple-cycle Combustion Turbine dispatch weighted Energy (Seasonal System Energy Combustion Turbine or SSECT) allocation factor. This process was described earlier in my testimony.

Because existing SCCTs are dispatched more heavily during the summer months, the majority of their costs are allocated using summer loads.

Seasonal Contracts

Q. Does Pacificorp propose to allocate the cost of Seasonal Contracts in the same way as SCCTs?

A. Generally, yes. As with the Simple-Cycle Combustion Turbines, the cost of Seasonal Contracts will be allocated on a weighted monthly basis according to their monthly delivered megawatt hours. Because some of the contracts do not have explicit Demand and Energy components, however, the entire contracts will be classified as 75 percent Demand and 25 percent Energy-Related and allocated to States using the seasonally weighted (Seasonal System Generation Purchases or SSGP) allocation factor.

Cholla Unit IV

Q. Are there any other Resources that are more heavily used in one season of the year?

A. Yes. The Cholla plant is considered a winter Seasonal Resource. Although the Cholla Unit IV is operated all year except for times of required maintenance, a substantial portion of the summer output is delivered to Arizona Pubic Service Company ("APS") and an equivalent amount of capacity and energy is returned to PacifiCorp during the winter months.

Q. How are the costs of the Cholla Unit IV to be allocated under the MSP Solution?

A. The costs of the Cholla plant are allocated using a similar monthly weighting methodology as used for SCCTs with an adjustment for the megawatt hours delivered to and received from APS. Both the demand and energy components of plant costs are assigned to months on the basis of monthly megawatt hours dispatched from Cholla plus megawatt hours received from APS less megawatt hours delivered to APS. This assigns the majority of the Cholla costs to five winter months, October through February.

Because Cholla is a baseload plant, fixed costs are classified as 75 percent Demand/25 percent Energy. The Fixed Costs are allocated using the Seasonal

System Generation Cholla (SSGCH) allocation factor and fuel costs are allocated using the Seasonal System Energy Cholla (SSECH) allocation factor.

System Resources

Q. What is the allocation procedure for the remaining System Resources?

A. The Fixed Costs of System Resources are allocated using the 75 percent Demand, 25 percent Energy 12 CP (System Generation or SG) allocation factor. Variable Costs for System Resources are allocated using the Annual Energy (System Energy or SG) allocation factor. The basis for these allocation factors and a description of how they are calculated were discussed earlier in my testimony.

Transmission Costs

Q. How does the MSP Solution propose to classify and allocate transmission costs?

A. Costs associated with transmission assets and firm wheeling expense are classified as 75 percent Demand/25 percent Energy-Related and allocated using the SG allocation factor. Non-firm wheeling expense and revenues are classified as Energy-Related and allocated among the States based upon the SE Factor.

Q. Would this allocation change with the implementation of an RTO?

A. In the future, should PacifiCorp become a participant in an RTO, charges from the RTO will be allocated among the States based upon the same billing determinants relied upon by the FERC in setting the RTO's rates.

Q. What would be the revenue requirement allocation implication of FERC requires that certain current transmission assets be refunctionalized?

A. Those that are refunctionalized as generation assets will be allocated consistent with the allocation of the fixed costs of the Resource with which they are associated. Those refunctionalized as distribution assets will be direct assigned to the State where they are physically located.

Distribution Costs

Q. Does the MSP Solution propose any change to the allocation of distribution costs?

A. No. Distribution costs are all directly assigned to individual States and no jurisdictional allocation is required.

Administrative and General (A&G) Costs

Q. With the change in the allocation of some of the generation plant costs, have you looked at the impact that these new allocation procedures have on the sharing of A&G and other infrastructure costs?

A. Yes, and the impacts appear to be minimal. Historically PacifiCorp has allocated the bulk of A&G expenses, the costs of General Plant and Intangible Plant, and other common costs using a System Overhead (SO) factor. The SO factor is calculated using each State's proportional share of allocated and assigned plant investment. With a change in the allocation for some of the generation assets, there will be a corresponding shift in the allocation of these common costs. To test whether that shift was significant enough to warrant development of a new allocation procedure, the Company compared the allocation of all costs using the SO factor under the proposed method with the allocation of those same costs under the rolled-in allocation method. The impact of the change in the SO factor was approximately plus or minus one percent of system overhead costs and less than 0.15 percent of total State revenue requirements. We did not consider this impact to be large enough to warrant a change in methodology for the allocation of system overhead costs.

Special Contracts

Q. What is the Company's proposal regarding the treatment of Special Contracts?

A. As described in the direct testimony of Ms. Kelly, the Company proposes that if a Commission makes a decision for reasons of local or State interest that increases costs to customers in other States, the costs of the decision should be borne entirely within the State making the decision. As applied to Special Contracts, the cost of serving contract customer loads, and their State approved retail service revenues, will be included in the local State's revenue requirement on the same basis as would apply to the cost of serving any other retail customer. Any payments made (or discounts provided) for the Customer Ancillary Service Contract attributes, such as operating reserves, system integrity interruption, or economic curtailment, will be treated as a Resource acquisition by the Company and included as a purchased power costs allocated among all States. If a buy-through option is provided with economic curtailment, both the cost and the revenue associated with the buy- through will be assigned situs to the host jurisdiction. This removes the effect of the buy-through from non-host jurisdictions and from all other customers in the host jurisdiction.

As with the establishment of retail tariff prices, the Commission with jurisdiction over a Special Contract will, within the context of the State revenue requirement, have authority to establish the retail service price for the contract. This includes the application of State-specific public policy preferences that may allow Commissions to consider other issues, in addition to costs, when setting retail prices.

Exhibit No. 14 shows an example of the impact of the proposed treatment of Special Contracts on State revenue requirements. This example assumes a three-jurisdiction system. Jurisdictions two and three each have Special Contracts and Jurisdiction one does not. Jurisdictional loads and potential resources are shown on lines 1 through 6. Allocation factors based on total State loads are shown on lines 8 through 11. The "No Ancillary Service Contracts" example, lines 16 through 23 show the resource cost of service and associated revenues assuming no ancillary services are acquired from the two Special Contracts. The second example, lines 28 through 48 show the resource cost of service and associated revenues assuming there are ancillary service components to each of the contracts.

In the "With Ancillary Service Contracts" example, Contract A has retail service revenue of $40 million and receives a $4 million discount for providing 100 MW of operating reserves. Contract B has retail service revenue of $20 million and receives a $3 million discount for allowing 75 MW of economic curtailment for up to 500 hours per year.

The $4 million discount, or payment, for reserves is identified as a

Resource acquisition and is shown on line 41 as part of the cost of service. Likewise the $3 million discount, or payment, for economic curtailment is also identified as a Resource acquisition and shown on lines 42 and 43. Because these Resources are obtained from the two customers rather than other sources, the Energy-Related and Demand-Related costs, shown on lines 39 and 40, are $7 million less than in the first example, lines 17 and 18, where there were no ancillary services contracts. Comparing line 19 with line 44, total cost of service, both total system and by jurisdiction, are equal whether or not the ancillary services are acquired from the contract customers.

As with total cost of service, jurisdictional revenues are also unchanged. The $40 million associated Contract A and the $20 million associated with Contract B continue to be identified as jurisdictional revenues and the revenues to be collected from all other customers, as shown on lines 23 and 48, remain unchanged.

Load Growth

Q. You testified that the MSP Solution allocates costs dynamically and, with the exceptions identified above, all States share in the cost of new Resources. Does this provision cause slow-growing States to subsidize fast-growing States?

A. As Mr. Duvall has testified, we do not believe this occurs to a material degree. During the MSP, PacifiCorp prepared an example that identified the implications of disproportionate load growth in one State and the Resources added to meet that growth. In the example, Utah's load was increased an additional 200 MW above the MSP forecast starting in 2010. Concurrently a 200 MW combined cycle gas plant was added to meet the additional load. Exhibit No. 15 shows the revenue requirement impacts of meeting the additional 200 MW. In this example, Utah picks up 94 percent in the total revenue requirement increase. While the example shows an impact of the other States, that impact was minimal.

Q. Why aren't more of the costs of the additional Resource passed on to other States?

A. While all States pick up their proportional share of the higher than system average costs of the new additional Resource, Utah, the faster growing State in this example, picks up a larger share of all other allocated costs. As a result of its now larger allocation factors, Utah picks up a larger share of the costs of the remaining generation Resources, a larger share of the system's transmission costs, a larger share of A&G expenses and all other allocated costs.

Revenue Requirement Impacts

Q. Have you prepared an exhibit showing the impact of the MSP Solution on revenue requirements?

A. Yes. Exhibit No. 16 presents estimates of impacts of the MSP Solution on each State's revenue requirement. Estimated MSP Solution revenue requirements for California, Oregon, Washington, and Wyoming are compared to the Modified Accord methodology. Estimated MSP Solution revenue requirements for Idaho and Utah are compared to the Rolled-In methodology. A positive percent indicates the States revenue requirement for a given year under the MSP Solution is higher and a negative percent indicates the revenue requirement under the MSP

Solution is lower. The year-by-year revenue requirement impacts are shown for the period 2005 thorough 2018 as well as the Net Present Value of the difference in revenue requirements over the 14-year period. For each State, the percent change in revenue requirement associated with the Hydro and Coal Endowments is shown first followed by the impact of the full MSP Solution.

Q. What do you conclude from Exhibit No.16?

A. I conclude that the revenue requirement impacts are within an acceptable range. The Net Present Value of the change in revenue requirement over the 14-year period is less than one percent for every State and single year impacts never exceed plus or minus 2.5 percent. While the MSP Solution produces somewhat lower revenue requirements for California, Oregon, Washington, and Wyoming in the early years, the trend reverses and those States see larger revenue requirements in the later years. The higher MSP Solution revenue requirements seen by Utah and Idaho in the early years are offset by lower revenue requirements in the later years.

Q. Have you prepared an exhibit that identifies how all cost components of the revenue requirement are allocated among States?

A. Yes. Exhibit No. 17, which is Appendix B of the Protocol, identifies the allocation factor applied to each component of the revenue requirement calculation. Exhibit No. 18, which is Appendix C of the Protocol, gives a detailed explanation and the algebraic formula for each allocation factor.

Q. Does this conclude your Direct Testimony?

A. Yes.